

**strength is
woven into
everything
we do**

Celtic Exploration Ltd.
2006 Annual Report

and it shows in all aspects of our success.
Our well-defined yet flexible business plan
allows us to react quickly to opportunities
created in today's unique market.

generated an average
operating netback in
2006 of \$38.81 per BOE

drilled 83 (62.8 net)
wells during the
year with an overall
success rate of 74%

increased oil and
gas reserves by 42%
to 26.4 million BOE

earnings per share (diluted)
of \$1.12, an increase of 75%
compared to \$0.64 in 2005

reported net earnings
of \$35.2 million, up 93%
compared to 2005

In 2006, Celtic Exploration Ltd. delivered its strongest annual earnings performance to date. This annual report tells the story of a management team committed to creating shareholder value, and a company with financial and operating strength.

increased average daily production by 35% to 5,963 BOE per day in 2006

continued to add to our future inventory by increasing our undeveloped land position by 43%

funds from operations per share (diluted) of \$2.50, an increase of 26% compared to \$1.98 in 2005

reported funds from operations of \$78.5 million, up 38% compared to 2005

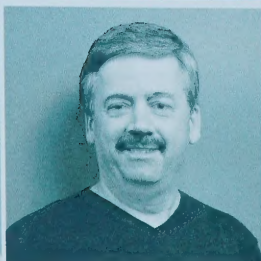
HIGHLIGHTS

Celtic Exploration Ltd. is a growth-oriented oil and gas exploration and production company based in Calgary, Alberta. Since commencing active oil and gas operations in 2002, the Company has rapidly grown its production base, resulting in record-high revenue and earnings in 2006.

(\$ thousands, unless otherwise indicated)	Three months ended December 31			Year ended December 31		
	2006	2005	Change	2006	2005	Change
FINANCIAL						
Revenue, net of royalties	\$ 33,091	\$ 26,647	24%	\$ 123,262	\$ 76,578	61%
Funds from operations	\$ 19,183	\$ 18,674	3%	\$ 78,541	\$ 56,969	38%
Funds from operations per share						
Basic <i>(\$/share)</i>	\$ 0.60	\$ 0.65	-8%	\$ 2.57	\$ 2.05	25%
Diluted <i>(\$/share)</i>	\$ 0.58	\$ 0.62	-6%	\$ 2.50	\$ 1.98	26%
Net earnings	\$ 6,599	\$ 7,062	-7%	\$ 35,231	\$ 18,264	93%
Earnings per share						
Basic <i>(\$/share)</i>	\$ 0.21	\$ 0.24	-13%	\$ 1.15	\$ 0.66	74%
Diluted <i>(\$/share)</i>	\$ 0.20	\$ 0.24	-17%	\$ 1.12	\$ 0.64	75%
Capital expenditures, net of dispositions	\$ 32,051	\$ 41,490	-23%	\$ 164,050	\$ 119,230	38%
Total assets				\$ 373,882	\$ 242,113	54%
Bank debt				\$ 101,800	\$ 41,700	
Working capital deficiency (surplus), excluding bank debt				(3,564)	21,726	
Bank debt, net of working capital				\$ 98,236	\$ 63,426	55%
Shareholders' equity				\$ 200,029	\$ 125,847	59%
Common shares issued and outstanding <i>(thousands)</i>						
Basic				32,180	28,973	11%
Diluted				34,810	31,229	11%

	Three months ended December 31			Year ended December 31		
	2006	2005	Change	2006	2005	Change
OPERATIONS						
Production						
Oil (<i>bbls/d</i>)	3,290	2,915	13%	3,284	2,524	30%
Natural gas (<i>mcf/d</i>)	18,001	13,071	38%	16,072	11,396	41%
Combined (<i>BOE/d</i>)	6,290	5,094	23%	5,963	4,423	35%
Production per million shares (<i>BOE/d</i>)	196	176	11%	195	159	23%
Realized sales prices, after financial derivatives						
Oil (<i>\$/bbl</i>)	\$ 58.68	\$ 57.49	2%	\$ 63.78	\$ 58.91	8%
Natural gas (<i>\$/mcf</i>)	\$ 10.10	\$ 12.51	-19%	\$ 9.71	\$ 9.63	1%
Operating netbacks (<i>\$/BOE</i>)						
Oil and gas revenue, before financial derivatives	\$ 53.99	\$ 67.05	-19%	\$ 58.97	\$ 60.21	-2%
Realized gain (loss) on financial derivatives	5.60	(2.05)	-	2.29	(1.80)	-
Royalties	(9.67)	(12.02)	-20%	(10.89)	(10.98)	-1%
Production expense	(13.38)	(10.59)	26%	(10.90)	(9.51)	15%
Transportation and selling expense	(0.75)	(0.63)	19%	(0.66)	(0.72)	-8%
Operating netback	\$ 35.79	\$ 41.76	-14%	\$ 38.81	\$ 37.20	4%
Drilling activity						
Total wells	10	27	-63%	83	100	-17%
Working interest wells	8.4	15.3	-45%	62.8	68.1	-8%
Success rate on working interest wells	65%	76%	-14%	74%	74%	0%
Undeveloped land						
Gross acres				323,821	261,346	24%
Net acres				235,308	164,239	43%
Reserves						
Oil (<i>mmbbls</i>)				11,634	10,527	11%
Natural gas (<i>mmcf</i>)				88,327	47,992	84%
Combined (<i>mBOE</i>)				26,355	18,526	42%
Reserve life index (<i>years</i>)				11.5	10.0	15%

we draw strength from
all aspects of the company



PRESIDENT'S MESSAGE

The year 2006 was once again a rewarding year for Celtic. The oil and gas industry was faced with a significant slowdown due to declining commodity prices resulting in lower cash flows; however, Celtic continued to aggressively drill and add land to its prospect inventory. To achieve this, the Company benefited from its commodity price contracts whereby Celtic had locked in high natural gas prices for both 2006 and 2007 at certain opportune times which resulted in Celtic achieving a netback of \$38.81 per barrel of oil equivalent in 2006. Also, the Company's product split which is approximately 50% light oil and liquids, along with lower than average royalties, enhanced the netback and associated cash flow.

After drilling two wells at Kaybob at the end of 2005, Celtic was able to tie up 30 sections of land in 2006, most at 100% working interest. The Company drilled a total of 14 wells in 2006 on the Kaybob South pool and other Montney prospects in the Kaybob area. With up to six or seven billion cubic feet per section of recoverable natural gas on this prospect, the Company has proceeded to down-space the Kaybob South pool to three wells per section. This leaves the Company with a very prolific development program in 2007.

Celtic had significant success in its other core areas as well, with new pools being discovered both at Swan Hills and Bantry. In total, 83 wells were drilled with a success rate of 74% in 2006. Although service and land costs were substantially higher, the Company's finding and development costs remained competitive, compared to industry, at \$16.40 per barrel of oil equivalent before future development capital and \$19.56 after future development capital. The all-in replacement cost gives Celtic a recycle ratio of 2.0 times which was achieved even after incurring over \$20 million for land, which will generate further benefits in 2007. The reserve life index increased again in 2006, growing to 11.5 years, which for a growing junior company is a valuable attribute.

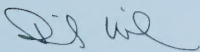
Capital expenditures for 2006 were \$164.0 million. The Company increased its capital budget several times during the year as new opportunities were internally generated. While carrying out this budget, Celtic was able to keep its debt at a satisfactory level of \$98.2 million compared to projected cash flow of \$100 million for 2007. Achieving this cash flow will be aided by a hedging program which will enable Celtic to receive over \$10.00 per thousand cubic feet on the majority of its natural gas production in the first quarter. As well, an average floor of US\$67.00 per barrel is guaranteed on 40% of the Company's estimated oil production in 2007.

Although natural gas prices at the end of 2006 had fallen to almost half of their record highs at the beginning of the year, Celtic was still able to increase its net asset value per share to \$12.25 on this much more modest natural gas price strip. This was accomplished by increasing total reserves by 42%.

Celtic was able to carry considerable momentum into 2007 with a diversified drilling program consisting of several new prospect areas which have had early success in 2007. The Kaybob development program will see as many as 22 infill wells drilled with more step-out wells and exploration wells adding to the Kaybob well count. In all, the Company plans to drill a total of 75 to 85 wells in 2007.

We would like to thank our shareholders for their continued support, the Board of Directors for their guidance and our employees for their effort and loyalty.

Celtic's Annual and Special Meeting of shareholders is scheduled for Tuesday, April 24, 2007 at 3:00 p.m., to be held at the Metropolitan Centre, 333 Fourth Avenue S.W., Calgary, Alberta.



David J. Wilson
President and Chief Executive Officer

March 12, 2007

MANAGEMENT TEAM *left to right*

David J. Wilson	Sadiq H. Lalani	Michael R. Shea	David C. Morgenstern	Alan G. Franks
<i>President & Chief Executive Officer</i>	<i>Vice President, Finance & Chief Financial Officer</i>	<i>Vice President, Land</i>	<i>Vice President, Exploration</i>	<i>Vice President, Operations</i>

our dual-prong strategy sets us apart

the acquisition of assets with exploitation potential

Celtic expects to continue to grow by implementing its dual-prong strategy to acquire assets with exploitation potential and, at the same time, implement its full-cycle exploration program.

This strategy has proved successful to date, as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002.

To complement this strategy, the Company has assembled a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities.

Celtic believes that its growth strategy will continue to increase funds from operations per share, net asset value per share, and production per share.

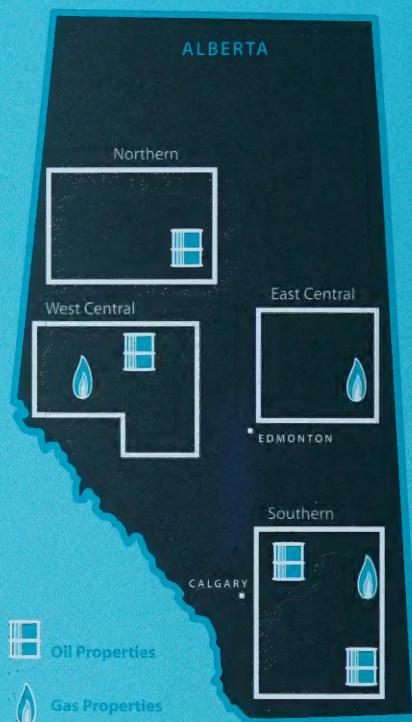


the implementation of full-cycle exploration programs

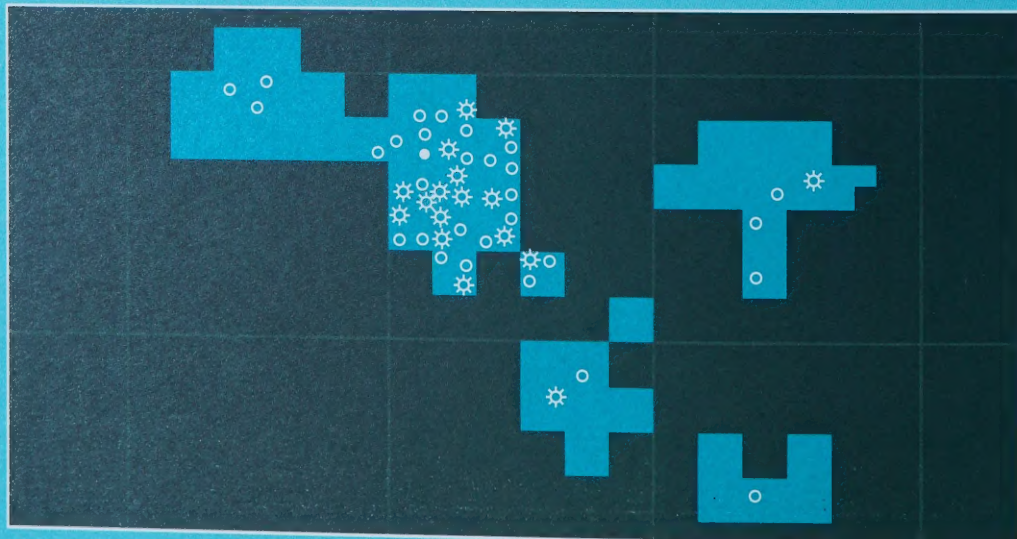
four key operating areas give us a diverse asset base

Celtic's continued land acquisition strategy is prospect-driven with emphasis on internally generated opportunities that are in close proximity to facility infrastructure.

- Oil Well
- ⚙ Natural Gas Well
- Drilling Location



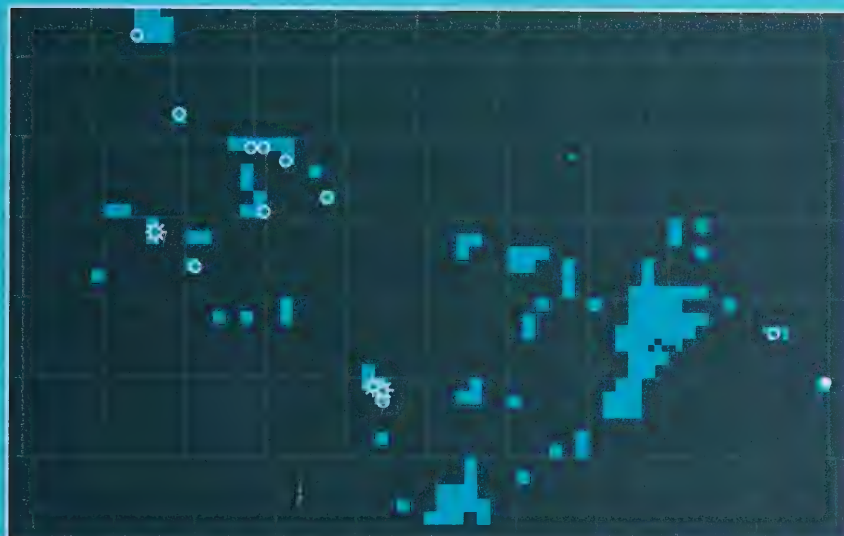
West Central Alberta Kaybob South



Celtic has established a large land position at Kaybob South where a new Montney natural gas pool is being developed.

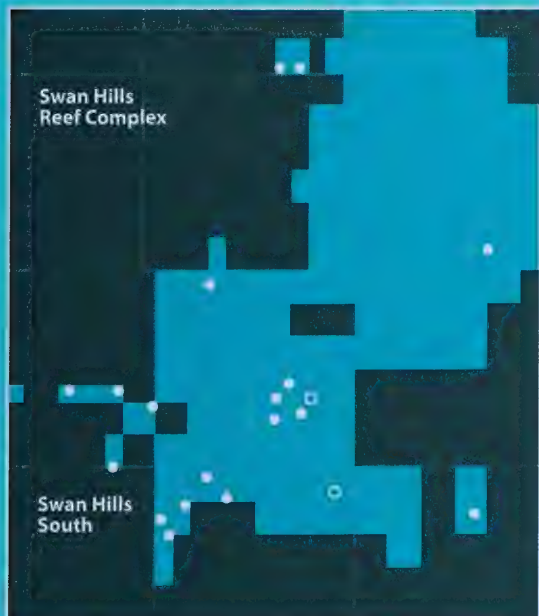
OPERATIONS

East Central Alberta **Ashmont/Figure Lake**



Ashmont/Figure Lake continues to provide Celtic with exposure to multi-zone natural gas potential at shallower depths of 500 to 700 metres.

West Central Alberta **Swan Hills** **Southern Alberta Princess/Bantry**



Swan Hills was the most active area for Celtic in 2006. Increased oil reserves are expected with the commencement of a waterflood in 2007.



Celtic has made a new pool discovery southwest of its Bantry oil pool which will be developed in 2007.

a year of strong growth in production

With new production recently brought on stream and with behind pipe volumes currently being tied in, Celtic expects to show continued production growth in the first half of 2007.

Production per million shares outstanding in 2006 averaged 195 BOE per day, up 23% from 159 BOE per day in 2005.

For 2006, production averaged 5,963 BOE per day (55% oil and 45% gas), resulting in a 35% increase from 4,423 BOE per day average production for 2005.

Oil and gas production in the fourth quarter of 2006 increased 23% to average 6,290 BOE per day compared to 5,094 BOE per day in the fourth quarter of 2005.

8,300-8,700 2007

5,963 2006

4,423 2005

3,608 2004

1,941 2003

MANAGEMENT'S DISCUSSION AND ANALYSIS

INTRODUCTION

The Company was incorporated on April 16, 2002 as Desco Exploration Ltd. and completed its initial public offering on June 27, 2002. On September 30, 2002, the Company changed its name to Celtic Exploration Ltd. ("Celtic" or the "Company"). Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the symbol "CLT."

The following management's discussion and analysis ("MD&A") should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2006. This MD&A is effective March 12, 2007. The accompanying financial statements of Celtic have been prepared by management and approved by the Company's Audit Committee and Board of Directors. These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Additional information relating to Celtic can be found on the SEDAR website at www.sedar.com.

Non-GAAP Financial Measurements This document contains the terms "funds from operations" and "operating netbacks" which do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Funds from operations and operating netbacks are used by Celtic as key measures of performance. Funds from operations and operating netbacks are not intended to represent operating profits nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. The reconciliation between net earnings and funds from operations can be found in the statement of cash flows included in the audited financial statements. Operating netbacks are determined by deducting royalties, production expenses and transportation and selling expenses from oil and gas sales revenue. The Company calculates funds from operations per share using the same method and shares outstanding which are used in the determination of earnings per share.

Other Measurements All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to oil in this discussion include crude oil and natural gas liquids ("NGLs"). NGLs include condensate, propane, butane and ethane.

Critical Accounting Estimates Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company.

Capitalized costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved reserves.

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Liability recognition for asset retirement obligations associated with oil and gas well sites and facilities is determined using estimated costs discounted based on the estimated life of the asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. Over time, the liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation.



In order to recognize stock-based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on Celtic's financial statements.

Changes in Accounting Policies and Practices Details outlining Celtic's accounting policies are contained in the notes to the financial statements. There have been no changes in the Company's accounting policies and practices in 2006, compared to the previous year.

Disclosure Controls and Procedures Disclosure controls and procedures are designed to provide reasonable assurances that all relevant information is gathered and reported to senior management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), on a timely basis in order that appropriate decisions can be made regarding public disclosure. As at December 31, 2006, the CEO and the CFO have evaluated the effectiveness of Celtic's disclosure controls and procedures as defined in Multilateral Instrument 52-109 of the Canadian Securities Administrators and have concluded that such disclosure controls and procedures are effective.

Internal Control over Financial Reporting The CEO and CFO are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. As at December 31, 2006, management, including the CEO and the CFO, has designed Celtic's internal controls over financial reporting as required by Multilateral Instrument 52-109 of the Canadian Securities Administrators.

During the review of the design of internal controls over financial reporting for the year ended December 31, 2006, it was noted that, due to the number of staff at Celtic, it is not feasible to achieve complete segregation of incompatible duties. However, other internal controls over financial reporting have been designed which provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections of any evaluation relating to the effectiveness in future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

GROWTH STRATEGY

Celtic's growth strategy is dual-pronged. The Company seeks to acquire assets with exploitation potential and, at the same time, implements its full-cycle exploration program. This strategy has proved successful to date as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002. To complement this strategy, the Company has assembled a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities. Celtic believes that its growth strategy will continue to increase funds from operations per share, net asset value per share and production per share.

RESULTS OF OPERATIONS

2006 Highlights The year ended December 31, 2006 was another successful year in the execution of the Company's growth strategy. Highlights for 2006 are as follows:

- Accumulated over 39 sections of land at Kaybob South where the Company made a Montney natural gas new pool discovery at the end of 2005;
- Generated gross proceeds of \$43.5 million by completing an equity financing that resulted in the issuance of 2.0 million common shares at a price of \$13.15 per share and a flow-through share private placement that resulted in the issuance of 1.0 million common shares at a price of \$17.25 per share;
- Drilled 83 (62.8 net working interest) wells during the year resulting in 24 (20.8 net) oil wells, 34 (25.3 net) natural gas wells and 3 (0.5 net) coal bed methane wells, for an overall success rate, based on net wells, of 74%;
- Reported earnings per share, diluted, of \$1.12, an increase of 75% compared to \$0.64 in 2005;
- Reported funds from operations per share, diluted, of \$2.50, an increase of 26% from \$1.98 in the previous year;
- Generated an average operating netback of \$38.81 per BOE, up 4% from \$37.20 per BOE in 2005;
- Increased average daily production by 35% to 5,963 BOE per day, up from 4,423 BOE per day in 2005 and achieved daily average production per million shares of 195 BOE per day, up 23% in 2006 compared to 159 BOE per day in the previous year;
- Increased proved plus probable reserves by 42% to 26.4 million BOE, up from 18.5 million BOE at December 31, 2005 and increased net undeveloped land holdings by 43% to 235,308 acres compared to 164,239 acres at December 31, 2005; and
- Improved the Company's net asset value per share at year-end to \$12.25, an increase of 6% compared to \$11.53 at December 31, 2005.

Production Oil and gas production in 2006 increased 35% to average 5,963 BOE per day compared to 4,423 BOE per day in 2005. Average production in the fourth quarter of 2006 was 6,290 BOE per day. Production per million shares outstanding in 2006 averaged 195 BOE per day, up 23% from 159 BOE per day in 2005. The following table provides a summary of daily average production:

Production Summary

Years ended December 31	2006	2005	2004
Oil (bbls/d)	3,284	2,524	2,283
Natural gas (mcf/d)	16,072	11,396	7,952
Combined (BOE/d)	5,963	4,423	3,608
Production per million shares (BOE/d)	195	159	140

Celtic's production is entirely based in Alberta and is divided into four core areas. In Southern Alberta, the Company's primary natural gas producing properties are located at Drumheller, Michichi and Richdale and its primary oil producing properties are located at Princess and Bantry. In East Central Alberta, the principal producing asset is a shallow natural gas property at Ashmont and Figure Lake. In Northern Alberta, the Company produces mainly light oil from Ogston, Otter and Utikuma Lake.



In West Central Alberta, Celtic has both natural gas and light oil production at Kaybob South, Fox Creek, Swan Hills, Ferrier and Kakwa/Lator. The following table provides a summary of daily average production in each core area:

Principal Producing Properties

(BOE/d) Years ended December 31	2006	2005	2004
West Central Alberta	3,049	1,530	1,114
Southern Alberta	1,838	1,865	1,475
Northern Alberta	605	638	630
East Central Alberta	471	390	389
Total	5,963	4,423	3,608

Revenue Revenue, after royalties, and after realized and unrealized gains or losses on financial derivatives, for the year ended December 31, 2006 was \$123.3 million, an increase of 61% compared to \$76.6 million in the previous year. For the three months ended December 31, 2006, revenue was \$33.1 million, up 24% from the fourth quarter of 2005. The breakdown of revenue for the past three years is summarized in the following table:

Revenue

Years ended December 31	2006		2005		2004	
	\$ thousands	\$/BOE	\$ thousands	\$/BOE	\$ thousands	\$/BOE
Oil revenue	76,442	63.78	54,278	58.91	40,775	48.79
Natural gas revenue	56,895	58.26	40,031	57.78	20,281	41.82
Royalties	(23,710)	(10.89)	(17,731)	(10.98)	(10,796)	(8.17)
Unrealized gain on financial derivatives	13,635	6.27	—	—	—	—
Revenue	123,262	56.64	76,578	47.43	50,260	38.04

The combined average product price received for oil and gas sales, adjusted for realized gains or losses on financial derivatives for the year ended December 31, 2006 was \$61.26 per BOE, an increase of 5% compared to the previous year. For the three months ended December 31, 2006, the average adjusted product price received was \$59.59 per BOE, down 8% from the average adjusted price received in the fourth quarter of 2005.

Oil Operations Oil production for the year ended December 31, 2006 averaged 3,284 bbls per day, an increase of 30% compared to the previous year. For the three months ended December 31, 2006, average oil production was 3,290 bbls per day, up 13% from the fourth quarter of 2005.

The average price received for oil sales, after realized financial derivatives, for the year ended December 31, 2006 was \$63.78 per bbl, an increase of 8% compared to the previous year. For the three months ended December 31, 2006, the average oil price received was \$58.68 per bbl, up 2% from the average price received in the fourth quarter of 2005.

For the year ended December 31, 2006, average oil royalties were 21.0% of sales, after financial derivatives (20.5% of sales, before financial derivatives). In the previous year, average oil royalties were 18.0% of sales, after financial derivatives (17.0% of sales, before financial derivatives). Celtic participated in various royalty incentive programs in 2006 and 2005, resulting in lower royalties for both years.

Transportation and selling expenses for oil production in 2006 averaged \$0.54 per bbl compared to \$0.61 per bbl in 2005. The lower per unit cost in 2006 reflects the smaller percentage of oil production that was trucked, in contrast to the previous year. For the year ended December 31, 2006, production expenses were \$12.30 per bbl. In the previous year, production expenses were \$10.93 per bbl. The higher per unit production expense in 2006 reflects the broad-based increase in service costs in the oil services industry and higher electricity prices resulting in higher power costs incurred to operate oil handling facilities. The breakdown of oil netbacks is summarized in the following table:

Oil Netback

Years ended December 31	2006		2005		2004	
	bbls/d	\$/bbl	bbls/d	\$/bbl	bbls/d	\$/bbl
Daily average production	3,284		2,524		2,283	
Sales price		65.43		62.06		48.79
Gain (loss) on financial derivatives		(1.65)		(3.15)		—
Royalties		(13.40)		(10.58)		(8.17)
Production expense		(12.30)		(10.93)		(8.28)
Transportation and selling expense		(0.54)		(0.61)		(0.46)
Oil netback		37.54		36.79		31.88

Natural Gas Operations Natural gas production for the year ended December 31, 2006 averaged 16,072 mcf per day, an increase of 41% compared to the previous year. For the three months ended December 31, 2006, average natural gas production was 18,001 mcf per day, up 38% from the fourth quarter of 2005.

The average price received for natural gas sales, after realized financial derivatives, for the year ended December 31, 2006 was \$9.71 per mcf, an increase of 1% compared to the previous year. For the three months ended December 31, 2006, the average natural gas price received was \$10.10 per mcf, down 19% from the average price received in the fourth quarter of 2005.

For the year ended December 31, 2006, average natural gas royalties were 13.4% of sales, after financial derivatives (15.3% of sales, before financial derivatives). In the previous year, average natural gas royalties were 19.9% of sales. Celtic participated in various royalty incentive programs in 2006 and 2005, resulting in lower royalties for both years.

Transportation and selling expenses for the year ended December 31, 2006 were \$0.13 per mcf, an improvement of 13% compared to \$0.15 per mcf for the previous year.

For the year ended December 31, 2006, production expenses were \$1.53 per mcf. In the previous year, production expenses were \$1.27 per mcf.



The breakdown of natural gas netbacks is summarized in the following table:

Natural Gas Netback

Years ended December 31	2006		2005		2004	
	mcf/d	\$/mcf	mcf/d	\$/mcf	mcf/d	\$/mcf
Daily average production	16,072		11,396		7,952	
Sales price		8.52		9.63		6.97
Gain on financial derivatives		1.19		—		—
Royalties		(1.30)		(1.92)		(1.36)
Production expense		(1.53)		(1.27)		(1.31)
Transportation and selling expense		(0.13)		(0.15)		(0.19)
Natural gas netback		6.75		6.29		4.11

Interest Expense The Company has a committed term credit facility. The authorized borrowing amount under this facility is \$115.0 million. Interest is payable monthly for borrowings through direct advances. Under the credit facility, borrowings through the use of bankers' acceptances are also available. Security is provided for by a floating charge debenture over all assets in the amount of \$250.0 million, general assignment of book debts and a fixed charge on the Company's major producing petroleum and natural gas properties. Repayments of principal are not required, provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The maturity date for the credit facility is May 5, 2007, at which time the financial institutions will complete their annual review and may extend the facility for a further period of 364 days.

Interest expense for the year was \$4.0 million at an average rate of 5.6% compared to \$1.1 million at an average rate of 4.2% in 2005.

Interest Expense

Years ended December 31	2006		2005		2004	
	\$ thousands	\$/BOE	\$ thousands	\$/BOE	\$ thousands	\$/BOE
Interest expense	3,959	1.82	1,079	0.67	540	0.41
Average debt outstanding	71,129		25,666		12,943	
Average interest rate (%)	5.6%		4.2%		4.2%	

GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses General and administrative expenses for the year ended December 31, 2006 were \$2.0 million or \$0.91 per BOE compared to \$1.9 million or \$1.19 per BOE in 2005. General and administrative expenses are reduced by overhead recovered on Company-operated properties. In addition, salaries relating to geological and geophysical personnel are capitalized. The following table provides a breakdown of general and administrative expenses:

General and Administrative Expenses

Years ended December 31	2006		2005		2004	
	\$ thousands	\$/BOE	\$ thousands	\$/BOE	\$ thousands	\$/BOE
Gross general and administrative expenses	5,505	2.53	4,707	2.92	3,170	2.40
Overhead recoveries	(2,989)	(1.37)	(2,339)	(1.45)	(1,227)	(0.93)
Capitalized overhead	(539)	(0.25)	(459)	(0.28)	(393)	(0.30)
General and administrative expenses	1,977	0.91	1,909	1.19	1,550	1.17

Employees

At December 31	2006	2005	2004
Head office	31	29	24
Field operations	8	6	4
Total employees	39	35	28

Stock-based Compensation Expense For the year ended December 31, 2006, stock-based compensation expense was \$1.1 million, compared to \$0.8 million in 2005. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions shown in the following table:

Stock-based Compensation Expense

Years ended December 31	2006		2005		2004	
	\$ thousands	\$/BOE	\$ thousands	\$/BOE	\$ thousands	\$/BOE
Stock-based compensation expense	1,121	0.52	844	0.52	605	0.46
Weighted average assumptions for stock options granted:						
Risk-free interest rate	4.25%		4.00%		3.49%	
Expected life in years	3.0		3.0		3.0	
Expected volatility	20%		22%		28%	
Expected dividend yield	—		—		—	

Depletion, Depreciation and Amortization The Company follows the full-cost method of accounting whereby all costs relating to the exploration and development of oil and gas reserves are capitalized. These capitalized costs, along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved oil and gas reserves as evaluated by independent engineers. Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25%. Estimated future costs relating to asset retirement obligations are provided for on a unit-of-production basis and the provision is included in depletion, depreciation and amortization.



Depletion, depreciation and amortization expense for the period ended December 31, 2006 was \$43.4 million or \$19.96 per BOE, compared to the previous year's amount of \$28.9 million or \$17.89 per BOE. The following table provides a summary of the amounts included in depletion, depreciation and amortization:

Depletion, Depreciation and Amortization

Years ended December 31	2006		2005		2004	
	\$ thousands	\$/BOE	\$ thousands	\$/BOE	\$ thousands	\$/BOE
Depletion – intangible P&NG assets	33,039	15.19	21,955	13.61	15,070	11.41
Depreciation – tangible P&NG assets	9,772	4.49	6,374	3.95	4,060	3.07
Depreciation – other assets	119	0.05	100	0.06	77	0.06
Amortization – asset retirement costs	503	0.23	434	0.27	350	0.26
Depletion, depreciation and amortization	43,433	19.96	28,863	17.89	19,557	14.80

Ceiling Test The Company performed a ceiling test calculation at December 31, 2006 in accordance with the CICA full-cost accounting guidelines. As a result of the calculation, Celtic was not required to record an impairment loss. In addition, based on the calculation in the previous year conducted at December 31, 2005, there was no impairment loss required. The forecasted future oil and gas prices for the next 10 years used in the ceiling test evaluation of the Company's proved reserves as at December 31, 2006 are included in the notes to the financial statements.

Taxes For the year ended December 31, 2006, Celtic provided for a provision of future income taxes in the amount of \$11.9 million. This amount differs from the expected provision for income taxes of \$16.2 million based on the statutory combined income tax rate of 34.5%, due to the differences between the resource allowance deduction and non-deductible Crown charges and non-taxable provincial tax credits ("Alberta Royalty Tax Credit" or "ARTC") and the recognition of a benefit of \$4.0 million related to substantively enacted changes to the federal income tax rate and resource-related deductions from income. These changes, which will be phased in over the next four years, will result in a lower corporate income tax rate, provide for the deduction of Crown royalties and eliminate the resource allowance deduction. An analysis of the income tax provision is included in the notes to the financial statements.

At December 31, 2006, Celtic had unused income tax deductions available of approximately \$222.0 million. A summary of these deductions, with corresponding rates of deductibility, is shown in the table below:

Income Tax Deductions

At December 31	2006		2005		2004	
	\$ thousands	Deduction rate	\$ thousands	Deduction rate	\$ thousands	Deduction rate
Canadian oil and gas property expense (COGPE)	39,300	10%	30,692	10%	23,707	10%
Canadian development expense (CDE)	70,900	30%	47,017	30%	23,634	30%
Canadian exploration expense (CEE)	41,700	100%	22,862	100%	5,813	100%
Undepreciated capital cost (UCC)	67,200	4% – 30%	39,568	4% – 30%	21,779	4% – 30%
Share issue costs	2,900	5 years	2,091	5 years	1,253	5 years
Income tax deductions	222,000		142,230		76,186	

Net Earnings and Funds from Operations Net earnings for the year ended December 31, 2006 were \$35.2 million (\$1.15 per share, basic and \$1.12 per share, diluted). During the same period, funds from operations were \$78.5 million (\$2.57 per share, basic and \$2.50 per share, diluted).

The following table provides detailed unit statistics on a barrel of oil equivalent basis:

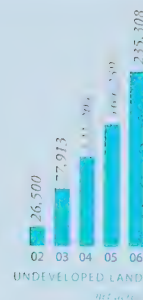
Unit Statistics

Years ended December 31	2006		2005		2004	
	BOE/d	\$/BOE	BOE/d	\$/BOE	BOE/d	\$/BOE
Daily average production	5,963		4,423		3,608	
Sales price		58.97		60.21		46.21
Gain (loss) on financial derivatives		2.29		(1.80)		—
Royalties, net of ARTC		(10.89)		(10.98)		(8.17)
Production expense		(10.90)		(9.51)		(8.12)
Transportation and selling expense		(0.66)		(0.72)		(0.72)
Operating netback		38.81		37.20		29.20
General and administrative expense		(0.91)		(1.18)		(1.17)
Interest expense		(1.82)		(0.67)		(0.41)
Capital tax		—		(0.06)		(0.08)
Funds from operations		36.08		35.29		27.54
Unrealized gain on financial derivatives		6.27		—		—
Stock-based compensation expense		(0.52)		(0.52)		(0.46)
Depletion, depreciation and amortization		(19.96)		(17.89)		(14.80)
Accretion of asset retirement obligation		(0.24)		(0.13)		(0.15)
Future income tax		(5.45)		(5.44)		(3.42)
Net earnings		16.18		11.31		8.71

INVESTMENT AND INVESTMENT EFFICIENCIES

Capital Expenditures Celtic is committed to future growth through its strategy to augment strategic oil and gas acquisitions with exploitation upside, and at the same time, implement a full-cycle exploration and development program. Since the Company began active oil and gas operations in September 2002, Celtic has completed several corporate and property acquisitions in order to establish a cash flow platform and an inventory of exploration and development prospects from which the Company can grow through the drill bit. Examples of where Celtic has successfully employed its strategy to acquire an initial position in an area, and subsequently expand the area making it core to the Company, include Fox Creek, Ashmont, Princess/Bantry and Swan Hills.

During the year ended December 31, 2006, Celtic incurred \$173.7 million on exploration and development activity, \$0.5 million on property acquisitions and received net proceeds of \$10.1 million from property dispositions. Drilling and completion operations accounted for \$104.9 million and equipment and facility expenditures were \$45.1 million. The balance of \$23.7 million was spent on land and seismic, building the Company's inventory of prospects for future drilling. Approximately 53% of net wells drilled were development and 47% were exploratory.



The Company's capital expenditures, including acquisitions and dispositions, for the past three years are summarized in the following table:

Capital Expenditures

Years ended December 31	2006		2005		2004	
	\$ thousands	% of total	\$ thousands	% of total	\$ thousands	% of total
Property, plant and equipment expenditures						
Lease acquisitions and retention	20,996	13%	6,676	6%	2,492	5%
Geological and geophysical activity	2,682	2%	2,941	2%	2,666	5%
Drilling and completion of wells	104,946	64%	79,202	67%	35,941	64%
Facilities, pipeline and well equipment	44,836	27%	25,075	21%	13,151	24%
Office furniture and equipment	220	—	153	—	225	—
	173,680	106%	114,047	96%	54,475	98%
Property, plant and equipment acquisitions	462	0%	5,213	4%	3,617	7%
Property, plant and equipment dispositions	(10,092)	-6%	(30)	—	(2,947)	-5%
Corporate acquisitions	—	—	—	—	—	—
Capital expenditures	164,050	100%	119,230	100%	55,145	100%

Undeveloped Land As at December 31, 2006, Celtic owned 235,308 net acres of undeveloped land, representing a 43% increase compared to 164,239 net acres at the end of 2005. Approximately 17% of the Company's undeveloped land position is subject to expiry in 2007, if not developed. Celtic holds an average working interest of 73% in its undeveloped lands.

In 2006, Celtic incurred \$20.2 million at Alberta Crown land sales, acquiring 68,950 net acres of petroleum and natural gas rights at an average cost of \$293 per acre, compared to an industry average of \$325 per acre. Of major significance was Celtic's acquisition of highly prospective Montney rights at Kaybob South. At December 31, 2006, Celtic owned a 100% interest in 25,280 acres (39.5 sections) of land at Kaybob South.

Looking ahead to 2007, Celtic will continue its internally generated, prospect-driven land acquisition strategy. This strategy will be complemented by third-party farm-in arrangements in core exploration areas. Celtic's land acquisition strategy remains focused on building a significant base of high working interest operated prospects, ensuring the Company is in a position to control its capital expenditure program.

The following table summarizes Celtic's land holdings as at December 31, 2006:

Undeveloped Land Holdings

As at December 31	2006		2005		2004	
(Acres)	Gross	Net	Gross	Net	Gross	Net
Alberta	318,204	232,088	255,720	161,013	198,918	117,983
British Columbia	4,815	2,819	4,815	2,820	4,815	2,820
Saskatchewan	802	401	811	406	802	401
Total owned undeveloped land	323,821	235,308	261,346	164,239	204,535	121,204
Option lands	—	—	95,680	64,556	147,000	119,000
Total controlled undeveloped land	323,821	235,308	357,026	228,795	351,535	240,204

Drilling During the year ended December 31, 2006, Celtic drilled 83 (62.8 net) wells compared to 100 (68.1 net) wells in the previous year, with an overall success rate of 74% on net wells drilled. The Company's average working interest in wells drilled during 2006 increased to 76% compared to an average working interest of 68% in 2005. The split between development drilling and exploratory drilling was 53% and 47%, respectively. The average depth of net wells drilled was 2,311 metres, 17% deeper than the average drilling depth of 1,967 metres in 2005. The following table summarizes Celtic's drilling activity in 2006:

Drilling Activity

Year ended December 31, 2006	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	18	16.4	6	4.4	24	20.8
Natural gas	16	13.5	18	11.8	34	25.3
Coal bed methane	3	0.5	—	—	3	0.5
Unsuccessful	3	3.0	19	13.2	22	16.2
Total wells	40	33.4	43	29.4	83	62.8
Success rate, based on net wells		91%		55%		74%

Reserves Celtic retains Sproule Associates Limited ("Sproule"), an independent qualified reserve evaluator to prepare a report on 100% of its oil and gas reserves. The Company has a Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves as at December 31, 2006 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101"). At December 31, 2006, Celtic's proved plus probable reserves were 26.4 million BOE, up 42% from 18.5 million BOE at the end of 2005. The following table outlines the change in the Company's reserves year-over-year including discoveries, drilling extensions, improved recoveries, technical revisions, economic factors, dispositions and production:

Reserves Reconciliation

	Oil		Natural Gas		Combined	
	Total proved mbbls	Proved + probable mbbls	Total proved mmcf	Proved + probable mmcf	Total proved mBOE	Proved + probable mBOE
Balance, December 31, 2005	6,267	10,527	29,012	47,992	11,103	18,526
Technical revisions	(107)	(1,182)	(3,909)	(9,812)	(759)	(2,817)
Discoveries	467	719	6,366	9,645	1,527	2,326
Extensions	1,106	1,628	12,009	19,354	3,108	4,854
Improved recoveries	393	1,393	13,509	30,229	2,645	6,431
Economic factors	(99)	(168)	(452)	(754)	(174)	(294)
Dispositions	(59)	(85)	(1,670)	(2,461)	(337)	(495)
Net additions	1,701	2,305	25,853	46,201	6,010	10,005
Production	(1,198)	(1,198)	(5,866)	(5,866)	(2,176)	(2,176)
Balance, December 31, 2006	6,770	11,634	48,999	88,327	14,937	26,355
Percentage increase in reserves	8%	11%	69%	84%	35%	42%



The Company created value for its shareholders in 2006, increasing the net present value (“NPV”) of proved plus probable reserves, discounted at 10% before tax, to \$470.6 million, up 21% from \$389.0 million at December 31, 2005. In addition, the quality of reserves improved, resulting in a reserve life index of 11.5 years compared to 10.0 years at December 31, 2005. At December 31, 2006, proved plus probable reserves were 44% oil and 56% natural gas. The following table outlines a summary of the Company’s reserves at December 31, 2006:

Summary of Reserves

As at December 31, 2006	Oil mmbbls	Gas mmcf	Combined mBOE	Q4 2006 Production BOE/d	Reserve Life Index years	NPV 10% BIT \$ thousands	NPV per BOE \$/BOE
Proved producing	6,174	29,099	11,024	6,290	4.8	254,471	23.08
Total proved	6,770	48,999	14,937	6,290	6.5	309,602	20.73
Total proved plus probable	11,634	88,327	26,355	6,290	11.5	470,559	17.85

Oil and gas selling prices have steadily increased over the past five years and current futures contracts indicate that prices will be higher in future years compared to historical averages. The following table outlines forecasted future prices that Sproule has used in their evaluation of the Company’s reserves at December 31, 2006:

Reference Prices

	Oil				Natural Gas		
	Currency exchange rate US\$/CA\$	WTI Cushing Oklahoma US\$/bbl	Edmonton Light par CA\$/bbl	Forecasted Celtic oil price¹ CA\$/bbl	Henry Hub Louisiana US\$/mmbtu	Alberta AECO-C Spot CA\$/mmbtu	Forecasted Celtic gas price² CA\$/mcf
Historical							
2002	0.637	26.09	40.12		3.22	4.04	
2003	0.716	31.14	43.23		5.39	6.66	
2004	0.770	41.42	52.91		6.14	6.87	
2005	0.826	56.46	69.29		8.62	8.58	
2006	0.882	66.09	73.31		7.23	7.16	
Five-year historical average	0.766	44.24	55.77		6.12	6.66	
Future forecasts							
2007	0.870	65.73	74.10	68.15	7.85	7.72	8.25
2008	0.870	68.82	77.62	72.10	8.39	8.59	9.15
2009	0.870	62.42	70.25	64.85	7.65	7.74	8.25
2010	0.870	58.37	65.56	60.19	7.48	7.55	8.05
2011	0.870	55.20	61.90	56.53	7.63	7.72	8.23
Five-year forecast average	0.870	62.11	69.89	64.36	7.80	7.86	8.39

¹ Celtic’s forecasted average oil price is based on total proved plus probable reserves and does not include NGLs.

² Celtic’s forecasted average gas price is based on proved plus probable reserves.

Sproule is forecasting WTI oil prices to average US\$62.11 per bbl over the next five years, 40% higher than the average price of US\$44.24 per bbl over the past five years. Similarly for natural gas, Henry Hub NYMEX natural gas prices are forecasted to average US\$7.80 per mmbtu over the 2007 to 2011 period, an increase of 27% from the average price of US\$6.12 per mmbtu during the 2002 to 2006 period.

During 2006, the Company's capital expenditures, net of dispositions, resulted in proved plus probable reserve additions (before technical revisions) of 12.8 million BOE, resulting in finding, development and acquisition ("FD&A") costs of \$12.79 per BOE (\$15.27 per BOE including future capital expenditures required to develop reserves). After technical revisions, FD&A costs were \$16.40 per BOE (\$19.56 per BOE including future capital expenditures required to develop reserves). The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per BOE to that year's reserve FD&A cost per BOE. Since incorporation, Celtic has successfully achieved a recycle ratio of 2.3 times on a proved plus probable basis. The following table provides detailed calculations relating to FD&A costs and recycle ratios for 2006:

Finding, Development and Acquisition Costs

	Year ended December 31, 2006	Year ended December 31, 2005	Year ended December 31, 2004	Cumulative since incorporation
Proved reserves				
Capital expenditures (\$000s)	164,050	119,230	55,145	424,608
Change in future capital costs required to develop reserves (\$000s)	18,811	7,211	3,662	30,852
Total capital costs (\$000s)	182,861	126,441	58,807	455,460
Reserve additions, before revisions (mBOE)	6,769	5,147	2,523	21,579
FD&A cost, before revisions and future capital (\$/BOE)	24.24	23.16	21.86	19.68
FD&A cost, before revisions, including future capital (\$/BOE)	27.01	24.57	23.31	21.11
Reserve additions, including revisions (mBOE)	6,010	5,631	2,609	20,792
FD&A cost, including revisions, before future capital (\$/BOE)	27.30	21.17	21.14	20.42
FD&A cost, including revisions and future capital (\$/BOE)	30.43	22.45	22.54	21.91
Operating netback (\$/BOE)	38.81	37.20	29.20	34.21
Recycle ratio – proved	1.3	1.7	1.3	1.6
Proved plus probable reserves				
Capital expenditures (\$000s)	164,050	119,230	55,145	424,608
Change in future capital costs required to develop reserves (\$000s)	31,690	13,856	6,535	53,598
Total capital costs (\$000s)	195,740	133,086	61,680	478,206
Reserve additions, before revisions (mBOE)	12,822	9,360	4,247	36,333
FD&A cost, before revisions and future capital (\$/BOE)	12.79	12.74	12.98	11.69
FD&A cost, before revisions, including future capital (\$/BOE)	15.27	14.22	14.52	13.16
Reserve additions, including revisions (mBOE)	10,005	9,089	4,283	32,210
FD&A cost, including revisions, before future capital (\$/BOE)	16.40	13.12	12.88	13.18
FD&A cost, including revisions and future capital (\$/BOE)	19.56	14.64	14.40	14.85
Operating netback (\$/BOE)	38.81	37.20	29.20	34.21
Recycle ratio – proved plus probable	2.0	2.5	2.0	2.3



Celtic's 2006 capital investment program replaced production by a factor of 2.8 times on a proved basis and 4.6 times on a proved plus probable basis. The following table summarizes production replacement for 2006:

Production Replacement

Year ended December 31, 2006	Proved			Proved plus probable		
	Oil mbbbls	Gas mmcf	Combined mBOE	Oil mbbbls	Gas mmcf	Combined mBOE
Reserve additions, including revisions	1,701	25,853	6,010	2,305	46,201	10,005
2006 production	1,198	5,866	2,176	1,198	5,866	2,176
Production replacement ratio	1.4	4.4	2.8	1.9	7.9	4.6

Net Asset Value Celtic's net asset value at December 31, 2006, discounting the present value of reserves at 10% before tax, increased to \$426.4 million (\$465.5 million using an 8% discount rate, before tax), up 18% from \$360.2 million at December 31, 2005. On a per share basis, net asset value increased 6% to \$12.25 per share (\$13.37 per share using an 8% discount rate, before tax). The present value of petroleum and natural gas ("P&NG") reserves was determined by Sproule in its year-end evaluation report. Undeveloped land at December 31, 2006 was valued at an average price of \$140 per acre. The components of net asset value are summarized in the following table:

Net Asset Value

At December 31	2006	2006	2005
	Forecast prices 8% Discount rate \$ thousands	Forecast prices 10% Discount rate \$ thousands	Forecast prices 10% Discount rate \$ thousands
Present value of P&NG reserves, discounted, before tax	509,732	470,559	389,030
Undeveloped land	32,949	32,949	19,709
Bank debt, net of working capital	(98,236)	(98,236)	(63,426)
Proceeds from exercise of stock options	21,097	21,097	14,849
Net asset value	465,542	426,369	360,162
Diluted common shares outstanding (thousands)	34,810	34,810	31,229
Net asset value per share (\$/share)	13.37	12.25	11.53

CAPITAL RESOURCES AND LIQUIDITY

Market Capitalization The Company's total capitalization increased 30% to \$586.9 million at December 31, 2006. Market value of common shares represented 76% of total capitalization, while debt and working capital represented 17% of total capitalization. The following table summarizes the Company's capitalization:

Capitalization

At December 31 (\$ thousands, except per share amounts)	2006		2005		2004	
Common shares outstanding (000s)	32,180		28,973		25,835	
Share price (last price traded at in the year)	13.91		12.40		9.30	
Market capitalization	447,624	76%	359,265	80%	240,266	84%
Bank debt, net of working capital	98,236	17%	63,426	14%	30,073	10%
Asset retirement obligation	4,885	1%	4,294	1%	3,307	1%
Future income taxes	36,162	6%	23,864	5%	15,680	5%
Total capitalization	586,907	100%	450,849	100%	289,326	100%

At December 31, 2006, the Company had \$101.8 million outstanding on its credit facility. Total debt, including working capital surplus, was \$98.2 million, representing approximately 1.3 times 2006 funds from operations and approximately 1.0 times forecasted 2007 funds from operations.

Key Debt Ratios

At December 31	2006		2005		2004	
	\$ thousands	Ratio	\$ thousands	Ratio	\$ thousands	Ratio
Bank debt	101,800		41,700		23,400	
Working capital deficiency (surplus)	(3,564)		21,726		6,673	
Total debt	98,236		63,426		30,073	
Debt to funds from operations ratio:						
Total debt	98,236		63,426		30,073	
Funds from operations	78,541		56,969		36,381	
Funds from operations – 2007 forecast	100,200					
Debt to funds from operations – trailing		1.3		1.1		0.8
Debt to funds from operations – forward		1.0		0.8		0.5
Asset coverage ratio:						
Total assets	373,882		242,113		135,984	
Total debt	98,236		63,426		30,073	
Asset coverage		3.8		3.8		4.5
Debt to equity ratio:						
Total debt	98,236		63,426		30,073	
Shareholders' equity	200,029		125,847		76,436	
Debt/equity		0.5		0.5		0.4



Source of Funds Investment funding for capital expenditures incurred in 2006 was provided by proceeds from equity financings, bank debt and cash provided by operating activities.

In May 2006, Celtic completed the issuance of 2.0 million common shares by way of private placement, at a price of \$13.15 per share, and in September 2006, the Company issued 1.0 million common shares on a flow-through basis by way of private placement, at a price of \$17.25 per share. These equity offerings resulted in gross proceeds of \$43.5 million.

The Company has in place a committed term credit facility with Canadian financial institutions. The maximum amount available to be drawn under this facility at December 31, 2006 was \$115.0 million. At December 31, 2006, Celtic had drawn \$101.8 million, leaving sufficient unused credit lines available to fund ongoing capital expenditures. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The maximum amount available under this credit facility may increase after the Company's lenders complete their annual review in May 2007.

In order to fund all capital expenditures incurred in 2006, the Company augmented its equity financing and bank borrowings by generating \$81.6 million in cash provided by operating activities for the year ended December 31, 2006.

Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

Working Capital The capital intensive nature of Celtic's activities may create a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At December 31, 2006, the working capital amount plus outstanding bank debt represented 82% of the Company's maximum authorized bank borrowing credit limit.

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas. This occurs on the 25th day following the month of sale. As a result, the Company's production revenues are collected in an orderly fashion. Celtic monitors its revenue counterparty credit positions to mitigate any potential credit losses. To the extent that the Company has joint venture partners in its activities, it must collect the partners' shares of capital expenditures and operating expenses on a monthly basis. Exceptions are in the event that the partners' shares of a capital project are significant amounts. In this case, Celtic will collect such amounts from its partners in advance of expenditures taking place in accordance with standard industry operating procedures. At December 31, 2006, the Company did not have any material accounts receivable that were deemed uncollectible.

Accounts payable consist of amounts payable to suppliers relating to head office and field operating and investing activities. These invoices are processed within the Company's normal payment period.

Celtic actively manages the pace of its capital spending program by monitoring forecasted production and commodity prices and resulting cash flows. Should circumstances affect cash flow in a detrimental way, the Company is capable of reducing capital investment levels.

Share Information The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at December 31, 2006, there were 32.2 million common shares outstanding. There were no preferred shares outstanding. As at December 31, 2006, directors, employees and consultants have been granted options to purchase 2.6 million common shares of the Company at an average exercise price of \$8.02 per share. Detailed information regarding the Company's stock options outstanding is contained in the notes to the financial statements. The Company's common

shares trade on the Toronto Stock Exchange ("TSX") under the symbol "CLT." The following table outlines Celtic's common share trading activity by quarter during the years 2006, 2005 and 2004:

Share Trading Activity (CLT)

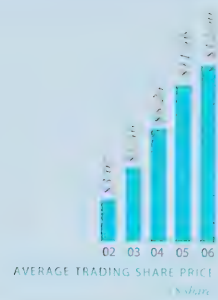
	Q1	Q2	Q3	Q4	2006
High (\$)	13.02	14.80	14.39	14.00	14.80
Low (\$)	11.06	11.90	12.15	11.83	11.06
Close (\$)	12.69	12.77	12.70	13.91	13.91
Volume traded (thousands)	3,100	1,882	2,855	1,644	9,482
Value traded (\$ thousands)	38,372	24,748	38,454	20,744	122,319
Weighted average trading price (\$)	12.38	13.15	13.47	12.62	12.90
	Q1	Q2	Q3	Q4	2005
High (\$)	12.45	11.75	13.50	12.91	13.50
Low (\$)	9.00	8.91	10.50	11.10	8.91
Close (\$)	11.00	11.15	12.90	12.40	12.40
Volume traded (thousands)	4,172	3,986	4,627	3,677	16,462
Value traded (\$ thousands)	45,333	42,390	56,662	44,290	188,675
Weighted average trading price (\$)	10.87	10.63	12.25	12.05	11.46
	Q1	Q2	Q3	Q4	2004
High (\$)	8.15	8.50	8.98	9.95	9.95
Low (\$)	6.70	7.11	7.60	8.40	6.70
Close (\$)	7.45	7.75	8.80	9.30	9.30
Volume traded (thousands)	2,511	2,660	2,075	2,823	10,069
Value traded (\$ thousands)	19,278	21,328	16,594	25,785	82,985
Weighted average trading price (\$)	7.68	8.02	8.00	9.13	8.24

Contractual Obligations Celtic has a committed term credit facility with Canadian financial institutions. The authorized borrowing amount under this facility as at December 31, 2006 was \$115.0 million, of which \$101.8 million was outstanding. Interest under this facility is payable monthly. Additional disclosure relating to bank debt is provided in the notes to the financial statements.

From time to time, the Company enters into agreements to transport and market oil and gas production. In addition, the Company has entered into agreements with third parties that provide employees with access to specialized computer software and information including production and reserves data, geological data, accounting systems and land management systems.

As a normal course of business, the Company leases office space, vehicles for field personnel and office equipment such as computers, printers and photocopiers.

Related-party Transactions The Company has retained the law firm of Borden Ladner Gervais LLP to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic, is a partner of this law firm. The Company expects to continue using the services of this law firm from time to time.



SUPPLEMENTAL QUARTERLY INFORMATION

The Company has been successful in providing strong growth in funds from operations and daily average production. The following tables summarize key financial and operating information by quarter:

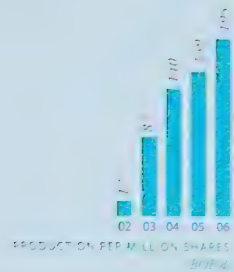
Quarterly Financial Information

(\$ thousands, except per share amounts)

2006	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	27,782	24,632	37,757	33,091	123,262
Funds from operations	20,538	18,008	20,812	19,183	78,541
Funds from operations per share – basic	0.71	0.60	0.70	0.60	2.57
Funds from operations per share – diluted	0.69	0.59	0.68	0.58	2.50
Net earnings	7,301	5,481	15,850	6,599	35,231
Earnings per share – basic	0.25	0.18	0.53	0.21	1.15
Earnings per share – diluted	0.24	0.18	0.52	0.20	1.12
Total assets	288,839	308,890	354,768	373,882	373,882
Bank debt, net of working capital	85,107	83,452	85,251	98,236	98,236
2005	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	14,099	13,645	22,186	26,647	76,577
Funds from operations	10,489	10,724	17,082	18,674	56,969
Funds from operations per share – basic	0.41	0.39	0.59	0.65	2.05
Funds from operations per share – diluted	0.39	0.38	0.57	0.62	1.98
Net earnings	3,018	2,455	5,729	7,062	18,264
Earnings per share – basic	0.12	0.09	0.20	0.24	0.66
Earnings per share – diluted	0.11	0.09	0.19	0.24	0.64
Total assets	155,257	178,574	207,074	242,113	242,113
Bank debt, net of working capital	43,277	29,589	42,003	63,426	63,426
2004	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	11,212	11,976	13,986	13,086	50,260
Funds from operations	8,195	8,472	10,155	9,559	36,381
Funds from operations per share – basic	0.32	0.33	0.39	0.37	1.41
Funds from operations per share – diluted	0.31	0.32	0.38	0.36	1.37
Net earnings	2,047	2,582	3,594	3,278	11,501
Earnings per share – basic	0.08	0.10	0.14	0.13	0.45
Earnings per share – diluted	0.08	0.10	0.14	0.12	0.43
Total assets	106,166	114,246	122,416	135,984	135,984
Bank debt, net of working capital	15,576	19,225	20,572	30,073	30,073

Quarterly Operating Information

2006	Q1	Q2	Q3	Q4	Total
Production					
Oil (bbls/d)	3,617	3,187	3,048	3,290	3,284
Natural gas (mcf/d)	14,322	13,134	18,759	18,001	16,072
Combined (BOE/d)	6,004	5,376	6,175	6,290	5,963
Production per million shares (BOE/d)	207	181	197	196	195
Realized sales prices, after derivatives					
Oil (\$/bbl)	62.11	63.98	70.99	58.68	63.78
Natural gas (\$/mcf)	11.40	9.31	8.31	10.10	9.71
Combined (\$/BOE)	64.63	60.69	60.31	59.59	61.26
Operating netbacks, after derivatives					
Oil (\$/bbl)	37.12	39.86	42.56	31.07	37.54
Natural gas (\$/mcf)	7.59	6.70	6.02	6.83	6.75
Combined (\$/BOE)	40.49	40.01	39.30	35.79	38.81
2005	Q1	Q2	Q3	Q4	Total
Production					
Oil (bbls/d)	2,269	2,067	2,833	2,915	2,524
Natural gas (mcf/d)	8,856	10,101	13,485	13,071	11,396
Combined (BOE/d)	3,745	3,751	5,081	5,094	4,423
Production per million shares (BOE/d)	145	136	176	176	159
Realized sales prices, after derivatives					
Oil (\$/bbl)	54.01	59.08	64.12	57.49	58.91
Natural gas (\$/mcf)	8.33	7.61	9.15	12.51	9.63
Combined (\$/BOE)	52.41	53.03	60.03	65.00	58.41
Operating netbacks, after derivatives					
Oil (\$/bbl)	35.80	34.99	40.32	35.37	36.79
Natural gas (\$/mcf)	5.05	5.26	5.83	8.38	6.29
Combined (\$/BOE)	33.64	33.42	37.94	41.76	37.20
2004	Q1	Q2	Q3	Q4	Total
Production					
Oil (bbls/d)	2,281	2,314	2,396	2,142	2,283
Natural gas (mcf/d)	8,054	7,372	8,086	8,292	7,952
Combined (BOE/d)	3,623	3,543	3,744	3,524	3,608
Production per million shares (BOE/d)	140	137	145	136	140
Realized sales prices					
Oil (\$/bbl)	42.89	45.79	53.06	53.08	48.71
Natural gas (\$/mcf)	6.57	7.29	6.91	7.13	6.97
Combined (\$/BOE)	41.59	45.07	48.86	49.04	46.15
Operating netbacks					
Oil (\$/bbl)	28.19	30.08	34.58	34.66	31.88
Natural gas (\$/mcf)	3.77	4.00	4.12	4.48	4.11
Combined (\$/BOE)	26.13	27.98	31.02	31.62	29.20



Factors that have caused variations over the quarters:

- The majority of Celtic's production growth has been the result of the Company's successful exploration and development drilling activities:
 - The Company estimates that approximately 80% of fourth quarter 2006 production came from exploration and development activities and the balance from acquisitions.
- In addition to drilling activities, oil and gas property acquisitions completed in 2004 and 2005 have also contributed to production growth:
 - The \$3.4 million acquisition of a property in the Morse River Unit at Swan Hills, completed in April 2004, added approximately 120 bbls per day of oil production.
 - In 2005, Celtic completed the acquisition of complementary oil and gas properties in the Swan Hills/Virginia Hills area of West Central Alberta for approximately \$2.5 million, adding approximately 350 BOE per day (73% oil and 27% natural gas).
- Revenue, funds from operations and earnings growth are primarily the result of production growth and increases in commodity prices.

BUSINESS RISKS

Celtic's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers, intermediate and senior producers and royalty trust organizations, to the much larger integrated petroleum companies. Celtic is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Celtic employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Celtic explores in areas that afford multi-zone prospect potential, targeting a range of shallower low-to-moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Celtic has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Celtic strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Celtic does not operate.

Celtic is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas production. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by world-wide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Celtic may periodically use futures and options contracts to hedge its exposure to the potentially adverse impact of commodity price volatility.

Exploration for and production of oil and gas are very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Celtic utilizes bank financing to support ongoing capital expenditures. Funds from operations also provide Celtic with capital required to grow its business. Equity and debt capital are subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Celtic maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

BUSINESS OUTLOOK

Advisory Regarding Forward-looking Statements Certain information with respect to Celtic contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, certain of which are beyond Celtic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Celtic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. In addition, the reader is cautioned that historical results are not necessarily indicative of future performance.

2007 Forecast Celtic is optimistic about its future prospects. The Company was successful in establishing a production base during the early months since commencing operations that provides a cash flow stream that can be re-invested in Celtic's ongoing exploration and development activity. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high-quality product stream that, on a historical basis, receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone potential for light gravity crude oil and liquids-rich natural gas.

Celtic's Board of Directors has approved a capital expenditure budget in the amount of \$140 million for 2007. This capital spending will be financed by funds from operations, bank credit lines and a flow-through share equity offering completed in February 2007.

After forecasting risked production discoveries, timing of production on-stream dates resulting from the Company's planned capital expenditures for 2007 and estimated decline rates on existing volumes, Celtic expects production in 2007 to average between 8,300 and 8,700 BOE per day (46% oil and 54% gas). This represents a 39% to 46% increase from average production of 5,963 BOE per day in 2006.

Political turmoil in major oil-producing regions around the world continues to remain in the headlines and could potentially put a strain on stable world oil supply in the future. However, high oil prices recorded in 2006 may have affected world oil demand negatively and the move by nations around the world to curtail carbon emissions may lead to the development



of other energy sources resulting in a slower growth for the demand for oil. As a result of these and other factors, Celtic expects oil prices to be lower in 2007 compared to 2006. Natural gas demand in North America was considerably lower in 2006 compared to the previous year, primarily due to milder weather causing lower heating demand and industrial demand destruction as a result of high prices realized towards the end of 2005. However, natural gas prices in 2007 should benefit from the reduced supply resulting from a slowdown in natural gas drilling in Canada during the past few months. The Company's commodity price assumptions for 2007 are US\$62.00 per barrel for WTI oil, US\$7.50 per mmbtu for natural gas and a US/Canadian exchange rate of US\$0.855. These prices compare to 2006 average prices of US\$66.22 per barrel for WTI oil, US\$7.26 per mmbtu for NYMEX natural gas and a U.S./Canadian exchange rate of US\$0.882.

After giving effect to the aforementioned production and commodity price assumptions and taking into effect commodity risk price management contracts in place (as outlined in detail in the notes to the financial statements), funds from operations for 2007 are forecasted to be approximately \$100.2 million or \$3.00 per share (\$2.90 per share, diluted) and net earnings are forecasted to be approximately \$10.7 million or \$0.32 per share (\$0.31 per share, diluted). Changes in forecasted commodity prices and variances in production estimates can have a significant impact on estimated funds from operations and net earnings. Please refer to the advisory regarding forward-looking statements shown above.

Bank debt, net of working capital, is estimated to reach \$123.7 million by the end of 2007 or approximately 1.2 times forecasted 2007 funds from operations.

Celtic's capital expenditure budget for 2007 will see the Company participate at high working interests in the drilling of approximately 75 to 85 wells during the year. Celtic continues to pursue property acquisitions that would complement its existing asset base and completion of such acquisitions would be over and above the Company's planned capital expenditure budget.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per share growth in production, funds from operations and earnings. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2007.

Additional information relating to Celtic, including the Company's Annual Information Form ("AIF") is filed on SEDAR and can be viewed on their website at www.sedar.com. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer at Celtic Exploration Ltd., Suite 500, 505 Third Street S.W., Calgary, Alberta, Canada, T2P 3E6. Further information relating to the Company is also available on its website at www.celticex.com.



**strength
shows in
our results**

MANAGEMENT'S REPORT

Management has prepared the accompanying financial statements of Celtic Exploration Ltd. in accordance with Canadian generally accepted accounting principles. Financial information presented throughout this annual report is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial information. Where appropriate, management has made informed judgments and estimates in accounting for transactions which affect the current accounting period but cannot be finalized with certainty until future periods. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

PricewaterhouseCoopers LLP was appointed by the Company's shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of Celtic's internal control systems and included such tests and procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. This Committee, consisting of non-management directors, meets with management and independent auditors to ensure that each group is properly discharging its responsibilities and to discuss adequacy of internal controls, accounting policies and financial reporting matters. The Audit Committee has reviewed the financial statements and has reported thereon to the Board of Directors. The Board has approved the financial statements for issuance to the shareholders.



David J. Wilson
President and Chief Executive Officer

March 12, 2007



Sadiq H. Lalani
*Vice President, Finance and
Chief Financial Officer*

AUDITORS' REPORT

To the Shareholders of Celtic Exploration Ltd.

We have audited the balance sheets of Celtic Exploration Ltd. as at December 31, 2006 and 2005, and the statements of operations and retained earnings and cash flows for the years ended December 31, 2006 and 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005, and the results of its operations and its cash flows for the years ended December 31, 2006 and 2005, in accordance with Canadian generally accepted accounting principles.

Price Waterhouse Coopers LLP

Chartered Accountants

March 12, 2007

BALANCE SHEET

As at December 31
(\$ thousands)

	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	\$ 824	\$ 1,812
Accounts receivable	19,278	22,582
Prepaid expenses	833	288
Financial derivative contracts (Note 9)	13,635	—
	<u>34,570</u>	<u>24,682</u>
Other assets	1,713	1,160
Property, plant and equipment (Note 2)	337,599	216,271
	<u>\$ 373,882</u>	<u>\$ 242,113</u>
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	\$ 26,804	\$ 46,408
Current portion of future income taxes (Note 6b)	4,202	—
Bank debt (Note 3)	101,800	41,700
	<u>132,806</u>	<u>88,108</u>
Asset retirement obligation (Note 4)	4,885	4,294
Future income taxes (Note 6b)	36,162	23,864
	<u>\$ 173,853</u>	<u>\$ 116,266</u>
SHAREHOLDERS' EQUITY		
Share capital (Note 5)	\$ 127,841	\$ 89,812
Contributed surplus (Note 5)	2,467	1,545
Retained earnings	69,721	34,490
	<u>\$ 200,029</u>	<u>\$ 125,847</u>
	<u>\$ 373,882</u>	<u>\$ 242,113</u>

The accompanying notes form an integral part of these financial statements.

ON BEHALF OF THE BOARD OF DIRECTORS:



Director



Director

STATEMENT OF OPERATIONS AND RETAINED EARNINGS

Years ended December 31

(\$ thousands, except per share amounts)

	2006	2005
REVENUE		
Oil and natural gas	\$ 128,344	\$ 97,207
Royalties	(23,710)	(17,730)
Realized gain (loss) on financial derivatives	4,993	(2,899)
Unrealized gain on financial derivatives (Note 9e)	13,635	—
	<u>\$ 123,262</u>	<u>\$ 76,578</u>
EXPENSES		
Production	\$ 23,712	\$ 15,352
Transportation and selling	1,438	1,168
Interest	3,959	1,079
General and administrative	1,977	1,909
Stock-based compensation (Note 5d)	1,121	844
Depletion, depreciation and amortization (Note 2)	43,433	28,863
Accretion of asset retirement obligation (Note 4)	526	213
	<u>\$ 76,166</u>	<u>\$ 49,428</u>
Earnings before taxes	\$ 47,096	\$ 27,150
Capital tax	—	100
Future income taxes (Note 6a)	11,865	8,786
Net earnings	\$ 35,231	\$ 18,264
Retained earnings, beginning of period	34,490	16,226
Retained earnings, end of period	\$ 69,721	\$ 34,490
Earnings per share		
Basic	\$ 1.15	\$ 0.66
Diluted (Note 7)	\$ 1.12	\$ 0.63

The accompanying notes form an integral part of these financial statements.

STATEMENT OF CASH FLOWS

Years ended December 31
(\$ thousands)

	2006	2005
OPERATING ACTIVITIES		
Net earnings	\$ 35,231	\$ 18,264
Items not affecting cash:		
Depletion, depreciation and amortization	43,433	28,863
Accretion of asset retirement obligation	526	213
Stock-based compensation	1,121	844
Unrealized gain on financial derivatives	(13,635)	—
Future income taxes	11,865	8,785
Funds from operations	\$ 78,541	\$ 56,969
Settlement of asset retirement obligations	(646)	(44)
Change in non-cash operating working capital (Note 10)	3,739	398
Cash provided by operating activities	\$ 81,634	\$ 57,323
FINANCING ACTIVITIES		
Increase in bank debt	\$ 60,100	\$ 18,300
Issue of common shares, net of costs	42,464	29,702
Cash provided by financing activities	\$ 102,564	\$ 48,002
INVESTING ACTIVITIES		
Property, plant and equipment expenditures	\$ (173,680)	\$ (114,047)
Property, plant and equipment acquisitions	(462)	(5,213)
Property, plant and equipment dispositions	10,092	30
Change in other assets	(553)	(750)
Change in non-cash investing working capital (Note 10)	(20,583)	16,405
Cash used in investing activities	\$ (185,186)	\$ (103,575)
Net change in cash and cash equivalents	\$ (988)	\$ 1,750
Cash and cash equivalents, beginning of period	1,812	62
Cash and cash equivalents, end of period	\$ 824	\$ 1,812

The accompanying notes form an integral part of these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2006 and December 31, 2005

(All tabular amounts in thousands, unless otherwise stated)

NOTE 1 SIGNIFICANT ACCOUNTING POLICIES

Nature of business Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated under the *Business Corporations Act* (Alberta) on April 16, 2002 as Desco Exploration Ltd. The Company changed its name to Celtic Exploration Ltd. on September 30, 2002. Celtic is an oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in Western Canada, primarily in Alberta.

Basis of presentation These financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

Measurement uncertainty The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the balance sheets as well as the reported amounts of revenues, expenses and cash flows during the periods presented. Actual results could differ materially from estimated amounts. The amounts recorded for stock-based compensation, depletion, depreciation and amortization of assets, the provision for asset retirement obligation costs and the provision for future income taxes are based on estimates. In addition, the ceiling test calculation is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Joint interests A portion of the Company's exploration, development and production activities is conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Cash and cash equivalents Cash and cash equivalents include cash on hand, demand deposits and investments in highly liquid money market instruments which are convertible to known amounts of cash in less than three months.

Financial instruments The fair market values of cash and cash equivalents, receivables, other current assets, payables and bank debt approximate their carrying values. From time to time, the Company may use derivative financial instruments to manage exposure to fluctuations in commodity prices and foreign currency exchange rates. All transactions of this nature entered into by the Company are related to an underlying financial position or to future petroleum and natural gas production. The Company does not use derivative financial instruments for speculative trading purposes.

Property, plant and equipment The Company follows the full-cost method of accounting, whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, production equipment and facilities, carrying costs directly related to unproved properties, and costs related to acquisition of petroleum and natural gas assets directly or by means of a business combination. These capitalized costs, along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves as evaluated by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs.

Gains or losses on the disposition of properties are not recognized unless the proceeds on disposition result in a change of 20 percent or more in the depletion rate.

Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25 percent.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the “ceiling test”). Under this test, an estimate is made of the ultimate recoverable amount from undiscounted future net cash flows based on proved reserves, which are determined by using forecasted future prices, plus unproved properties. If the carrying amount exceeds the ultimate recoverable amount, an impairment loss is recognized in net earnings. The impairment loss is limited to the amount by which the carrying amount exceeds: (i) the sum of the fair value of proved and probable reserves; and (ii) the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Asset retirement obligations Estimated future costs relating to retirement obligations associated with oil and gas well sites and facilities are recognized as a liability, at fair value. The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. The liability is adjusted at each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability.

Future income taxes The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Flow-through shares Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as a future income tax liability and a reduction in share capital, at the time the renunciation documents are filed with the appropriate tax authorities.

Revenue recognition Revenue from the sale of oil and natural gas is recorded when title passes to an external party.

Stock-based compensation The Company has a stock-based compensation plan and uses the fair-value method to record compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant and a provision for the costs is provided for as contributed surplus over the term of the option agreement. The consideration received by the Company on the exercise of share options is recorded as an increase to share capital together with corresponding amounts previously recognized in contributed surplus. Forfeitures are accounted for as they occur which could result in recoveries of the compensation expense.

Per share amounts Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period.

Diluted per share amounts are calculated using the treasury stock method which assumes that any proceeds obtained on exercise of share options or other dilutive instruments would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

NOTE 2 PROPERTY, PLANT AND EQUIPMENT

At December 31, 2006	Cost	Accumulated depletion, depreciation and amortization	Net book value
Oil and gas properties, plant and equipment	\$ 434,385	\$ 100,199	\$ 334,186
Asset retirement obligation costs	4,879	1,974	2,905
Head office assets	852	344	508
	\$ 440,116	\$ 102,517	\$ 337,599

At December 31, 2005	Cost	Accumulated depletion, depreciation and amortization	Net book value
Oil and gas properties, plant and equipment	\$ 270,555	\$ 57,388	\$ 213,167
Asset retirement obligation costs	4,168	1,471	2,697
Head office assets	632	225	407
	\$ 275,355	\$ 59,084	\$ 216,271

At December 31, 2006, oil and gas properties with a cost of \$32.8 million (December 31, 2005 – \$16.7 million) relating to unproved properties have been excluded from the depletion and depreciation calculation. Future capital costs required to develop proved reserves in the amount of \$30.9 million (2005 – \$12.0 million) are included in the depletion and depreciation calculation.

In 2006, the Company capitalized \$0.5 million (2005 – \$0.5 million) with respect to employee salaries directly relating to exploration and development activities.

As a result of the ceiling test calculation at December 31, 2006, the Company was not required to record an impairment loss. The forecasted future prices used for the next 10 years in the ceiling test evaluation of the Company's proved reserves as at December 31, 2006 were as follows:

	2007	2008	2009	2010	2011
Oil (\$/bbl)	\$ 67.87	\$ 71.48	\$ 63.89	\$ 59.17	\$ 55.51
NGLs (\$/bbl)	60.00	62.56	55.95	51.72	48.54
Natural gas (\$/mcf)	8.26	9.23	8.31	8.10	8.28
	2012	2013	2014	2015	2016
Oil (\$/bbl)	\$ 56.37	\$ 57.31	\$ 58.32	\$ 59.22	\$ 59.80
NGLs (\$/bbl)	49.43	50.39	51.35	52.20	53.19
Natural gas (\$/mcf)	8.41	8.56	8.69	8.84	8.99

Prices escalate at approximately 1.5% thereafter.

NOTE 3 BANK DEBT

At December 31	2006	2005
Bank loan	\$ 51,800	\$ 21,700
Bankers' acceptances	50,000	20,000
	\$ 101,800	\$ 41,700

Celtic has a committed term credit facility with Canadian financial institutions. The authorized borrowing amount under this facility is \$115.0 million. Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime to bank prime plus 1.5%, depending upon the Company's then current debt to cash flow ratio of between less than one times to greater than three times. At December 31, 2006, interest was payable at bank prime. Under the credit facility, borrowings through the use of bankers' acceptances are also available. The Company has a fixed rate bankers' acceptance in the amount of \$50.0 million maturing on March 19, 2007 at an aggregate interest rate of 5.1%. Security is provided for by a floating charge debenture over all assets in the amount of \$250.0 million, general assignment of book debts and a fixed charge on the Company's major producing petroleum and natural gas properties.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The maturity date for the credit facility is May 5, 2007, at which time the banks will complete their annual review. The banks may conduct an interim review prior to May 5, 2007.

NOTE 4 ASSET RETIREMENT OBLIGATION

The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

At December 31	2006	2005
Asset retirement obligation, beginning of year	\$ 4,294	\$ 3,307
Liabilities incurred, net of liabilities disposed	736	797
Liabilities settled	(646)	(44)
Revisions to estimated liabilities	(25)	21
Accretion expense	526	213
Asset retirement obligation, end of year	\$ 4,885	\$ 4,294

The key assumptions on which the carrying amount of the asset retirement obligations is based include a credit-adjusted risk-free rate of 8.5% and an inflation rate of 2.5%. The total undiscounted amount of the estimated cash flows required to settle the obligations is \$20.7 million (December 31, 2005 – \$12.4 million). The inflated value of estimated cash flows required to settle the obligations at a future period at the time the asset is retired is \$43.6 million (December 31, 2005 – \$19.4 million). The expected timing of payment of the cash flows required to settle the obligations ranges from six years to 52 years.

NOTE 3 SHARE CAPITAL

A Authorized

Unlimited number of common shares.

Unlimited number of preferred shares.

B Issued

The following table summarizes the changes in common shares outstanding during the years ended December 31, 2005 and December 31, 2006:

	Common shares	Amount
Balance, December 31, 2004	25,835	\$ 59,446
Issued for cash on exercise of stock options	138	550
Amount relating to exercised options previously recorded as contributed surplus	—	63
Issued for cash through private placement	3,000	30,750
Share issue costs, after future income taxes	—	(997)
Balance, December 31, 2005	28,973	\$ 89,812
Issued for cash on exercise of stock options	207	1,035
Amount relating to exercised options previously recorded as contributed surplus	—	200
Issued for cash through private placement	2,000	26,300
Issued for cash through flow-through private placement	1,000	17,250
Future income tax benefit transferred on flow-through share issue	—	(5,367)
Share issue costs, after future income taxes	—	(1,389)
Balance, December 31, 2006	32,180	\$ 127,841

■ Flow-through shares

On September 7, 2006, Celtic issued 1.0 million common shares on a flow-through basis at an issue price of \$17.25 per share for gross proceeds of \$17.25 million. At December 31, 2006, the Company had an estimated \$7.2 million remaining obligation to incur Canadian Exploration Expenditures ("CEE"), which must be completed by December 31, 2007.

■ Stock options

Celtic has a stock option plan that provides for granting of stock options to directors, officers, employees and consultants. Stock options granted under the stock option plan have a maximum term of five years to expiry. Vesting is determined by the Company's board of directors. However, the majority of the options granted vest equally over a three-year period commencing on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day of grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes the changes in stock options outstanding during the years ended December 31, 2005 and December 31, 2006:

	Number of options	Average exercise price
Balance, December 31, 2004	1,928	\$ 5.28
Granted	466	11.22
Exercised	(138)	3.99
Forfeited	—	—
Balance, December 31, 2005	2,256	\$ 6.58
Granted	581	12.53
Exercised	(207)	4.99
Forfeited	—	—
Balance, December 31, 2006	2,630	\$ 8.02

The Company uses the fair-value method to record stock-based compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2006	2005
Risk-free interest rate	4.25%	4.00%
Expected life (years)	3.0	3.0
Expected volatility	20%	22%
Expected dividend yield	—	—
Fair value of options granted during the year (\$/share)	2.49	2.31

The following table summarizes information regarding stock options outstanding at December 31, 2006:

Range of exercise prices per share	Number of options outstanding	Weighted average remaining term in years	Weighted average exercise price per share for options outstanding	Number of options exercisable	Weighted average exercise price per share for options exercisable
\$ 2.01 – \$ 4.00	427	0.8	\$ 3.05	427	\$ 3.05
\$ 4.01 – \$ 6.00	675	1.7	5.48	675	5.48
\$ 6.01 – \$ 8.00	451	2.5	7.38	318	7.25
\$ 8.01 – \$10.00	30	2.8	8.65	20	8.65
\$10.01 – \$12.00	466	3.6	11.22	155	11.22
\$12.01 – \$14.00	581	4.6	12.53	–	–
Total	2,630	2.7	\$ 8.02	1,595	\$ 5.78

NOTE 6 INCOME TAXES

A Future income tax expense

The provision for income taxes differs from the expected amount calculated by applying the combined federal and provincial corporate income tax rate as a result of the following:

	2006	2005
Earnings before taxes	\$ 47,096	\$ 27,150
Statutory combined federal and provincial income tax rate	34.49%	37.62%
Expected income taxes	16,244	10,214
Increase (decrease) resulting from:		
Non-deductible Crown payments	2,078	2,890
Non-deductible stock-based compensation costs	387	286
Non-taxable provincial royalty credits (ARTC)	(60)	(110)
Allowable resource allowance deduction	(2,797)	(3,677)
Benefit relating to changes in future income tax rates	(4,008)	(833)
Other adjustments	21	16
Provision for future income taxes	\$ 11,865	\$ 8,786

B Future income tax liability

The components of future income taxes are as follows:

At December 31	2006	2005
Future income tax liabilities:		
Property, plant and equipment	\$ 38,642	\$ 26,072
Unrealized financial derivative gains	4,202	–
Future income tax assets:		
Asset retirement obligation costs	(1,505)	(1,455)
Share issue costs	(936)	(708)
Other income tax assets	(39)	(45)
Net future income tax liability	\$ 40,364	\$ 23,864
Less: current portion	(4,202)	–
Future income taxes	\$ 36,162	\$ 23,864

NOTE 7 EARNINGS PER SHARE

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under this method, only “in-the-money” dilutive instruments impact the calculations in computing diluted earnings per share.

In computing diluted earnings per share, 0.8 million (2005 – 0.8 million) shares were added to the 30.6 million (2005 – 27.8 million) weighted average number of common shares outstanding during the year for the dilutive effect of stock options.

NOTE 8 COMMITMENTS

The Company is committed to payments under a rental agreement for office space as follows:

	Amount
2007	\$ 536
2008	536
2009	535
2010	535
2011	179
	\$ 2,321

Rental leases relating to office space expire on April 30, 2011.

NOTE 9 FINANCIAL INSTRUMENTS

A Fair values of financial assets and liabilities

Financial instruments of the Company consist mainly of cash and cash equivalents, receivables, payables and bank debt. At December 31, 2006 and 2005, there were no significant differences between the carrying amounts reported on the balance sheets and their estimated fair values.

B Credit risk

The majority of the Company's accounts receivable is in respect of oil and gas operations. Celtic generally extends unsecured credit to these third parties, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Celtic has not experienced any material credit loss in the collection of receivables in 2006 and 2005.

C Interest rate risk

The Company is exposed to fluctuations in interest rates on its bank debt. Interest rate risk is mitigated through short-term fixed-rate borrowings using bankers' acceptances.

D Foreign exchange rate risk

The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices.

E Commodity risk management

From time to time, the Company may use financial derivative instruments to manage its exposure to fluctuations in commodity prices and foreign currency exchange rates. Under the terms of certain financial derivative contracts, Celtic may be required to provide security from time to time, depending on the underlying market value of those contracts.

The Company accounts for financial derivative instruments using the Canadian accounting standard outlined in the *CICA Handbook Accounting Guideline 13*, “Hedging Relationships.” This guideline addresses the identification, designation and effectiveness of financial contracts for the purpose of applying hedge accounting. Under this guideline, financial derivative

contracts must be designated to the underlying revenue or expense stream that they are intended to hedge, and tested to ensure they remain sufficiently effective. For transactions that do not qualify as designated hedges, the Company applies a fair-value method of accounting by initially recording an asset or liability, and recognizing changes in the fair value of the derivative instrument in income.

The following is a summary of oil sales price derivative contracts in effect as at December 31, 2006, that have fixed future sales prices (Fixed oil prices are based on the West Texas Intermediate [WTI] Index.):

Daily quantity	Remaining term of contract	Fixed price per bbl
1,000 bbls/d (costless collar)	January 1 to December 31, 2007	US\$65.00 (floor) US\$85.00 (cap)
500 bbls/d (costless collar)	January 1 to December 31, 2007	US\$70.00 (floor) US\$85.00 (cap)

The fair value of the above oil contracts, mark-to-market at December 31, 2006, is an unrealized gain of \$3.2 million.

The following is a summary of natural gas sales price derivative contracts in effect as at December 31, 2006, that have fixed future sales prices (Fixed natural gas prices are based on the New York Mercantile Exchange ["NYMEX"] Index or the AECO-C/NIT ["AECO"] Index, as indicated.):

Daily quantity	Remaining term of contract	Fixed price per mmbtu (NYMEX)
4,000 mmbtu/d	January 1 to March 31, 2007	US\$11.03
6,000 mmbtu/d	January 1 to March 31, 2007	US\$10.10
7,000 mmbtu/d (put option)	April 1 to October 31, 2007	US\$7.50
10,000 mmbtu/d (costless collar)	November 1 to December 31, 2007	US\$7.50 (floor) US\$12.40 (cap)

Daily quantity	Remaining term of contract	Fixed price per GJ (AECO)
4,000 GJ/d	January 1 to March 31, 2007	\$ 10.04
4,000 GJ/d	January 1 to March 31, 2007	\$ 9.01
10,000 GJ/d	April 1 to October 31, 2007	\$ 6.91
4,000 GJ/d	November 1 to December 31, 2007	\$ 9.06

The fair value of the above natural gas contracts, mark-to-market at December 31, 2006, is an unrealized gain of \$10.4 million.

In addition to financial derivative instruments, the Company may, from time to time, enter into physical fixed-price sales contracts in order to manage its exposure to fluctuations in commodity prices and foreign currency exchange rates. The following is a summary of natural gas physical fixed-price sales contracts in effect as at December 31, 2006, that have fixed future sales prices (Fixed natural gas prices are based on the AECO Index.):

Daily quantity	Remaining term of contract	Fixed price per GJ (AECO)
2,000 GJ/d	April 1 to October 31, 2007	\$ 7.59
2,000 GJ/d	April 1 to October 31, 2007	\$ 7.40
4,000 GJ/d	April 1 to October 31, 2007	\$ 7.20

NOTE 10 SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital, excluding bank debt:

	2006	2005
Accounts receivable	\$ 3,304	\$ (12,450)
Prepaid expenses	(545)	6
Accounts payable and accruals	(19,603)	29,247
Change in non-cash working capital	\$ (16,844)	\$ 16,803
Relating to:		
Operating activities	\$ 3,739	\$ 398
Investing activities	(20,583)	16,405
Change in non-cash working capital	\$ 16,844	\$ 16,803

During the year, the Company made the following cash outlays in respect of interest expense and capital taxes:

	2006	2005
Interest expense	\$ 4,310	\$ 972
Capital tax	195	150

NOTE 11 SUBSEQUENT EVENT

On February 27, 2007, Celtic completed an equity offering by way of private placement, whereby the Company issued 1.5 million flow-through common shares of the Company at a price of \$16.65 per share. As a result, the Company will have an obligation to incur CEE in the amount of \$25.0 million prior to December 31, 2008.

focus on light oil and liquids-rich natural gas with high netbacks and long reserve life

target adding reserves at \$14.00 to \$16.00 per BCF

Celtic Exploration chooses oil and gas assets with an eye to the future. We seek profitable production for today and a dramatic upside for tomorrow. The Company plans to aggressively carry out the capital expenditure budget. Celtic has assembled a large inventory of development drilling prospects, which will provide consistent production additions in 2007, and continues to expand its exploratory inventory of prospects.

acquire under-exploited properties and identify large area farm-in opportunities

**a strong
investment
in our future**

CORPORATE INFORMATION

BOARD OF DIRECTORS

Robert J. Dales ^{2, 3, 4}
President, Valhalla Ventures Inc.

William C. Guinan ^{1, 5}
Partner, Borden Ladner Gervais LLP

Eldon A. McIntyre ^{2, 3, 4}
President, Jarrod Oils Ltd.

Neil G. Sinclair ^{2, 4, 5}
President, Sinson Investments Ltd.

David J. Wilson ^{3, 5}
*President & Chief Executive Officer,
 Celtic Exploration Ltd.*

OFFICERS

David J. Wilson
President & Chief Executive Officer

Sadiq H. Lalani
*Vice President,
 Finance & Chief Financial Officer*

Michael R. Shea
Vice President, Land

David C. Morgenstern
Vice President, Exploration

Alan G. Franks
Vice President, Operations

¹ Chairman of the Board

² Member of the Audit Committee

³ Member of the Reserves Committee

⁴ Member of the Compensation Committee

⁵ Member of the Disclosure Committee

HEAD OFFICE

Suite 500
 505 Third Street S.W.
 Calgary, Alberta
 T2P 3E6
 Phone: 403.201.9153
 Fax: 403.201.9163
 www.celticex.com

REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
 Suite 310, 606 Fourth Street S.W.
 Calgary, Alberta
 T2P 1T1

LEGAL COUNSEL

Borden Ladner Gervais LLP
 1000 Canterra Tower
 400 Third Avenue S.W.
 Calgary, Alberta
 T2P 4H2

BANKERS

National Bank of Canada
 Suite 2700, 530 Eighth Avenue S.W.
 Calgary, Alberta
 T2P 3S8

AUDITORS

PricewaterhouseCoopers LLP
 Suite 3100
 111 Fifth Avenue S.W.
 Calgary, Alberta
 T2P 5L3

EVALUATION ENGINEERS

Sproule Associates Limited
 Suite 900
 140 Fourth Avenue S.W.
 Calgary, Alberta
 T2P 3N3

STOCK EXCHANGE LISTING

Toronto Stock Exchange
 Trading symbol "CLT"

ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
BOE	barrels of oil equivalent
mBOE	thousand barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
GJ	gigajoules
AECO-C	Alberta Energy Company "C" Meter Station of the Nova Pipeline System
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
CICA	Canadian Institute of Chartered Accountants
BIT	before income taxes
WTI	West Texas Intermediate

CONVERSION OF UNITS

Imperial = Metric

1 acre = 0.4 hectares

2.5 acres = 1 hectare

1 bbl = 0.159 cubic metres

6.29 bbls = 1 cubic metre

1 foot = 0.3048 metres

3.281 feet = 1 metre

1 mcf = 28.2 cubic metres

0.035 mcf = 1 cubic metre

1 mile = 1.61 kilometres

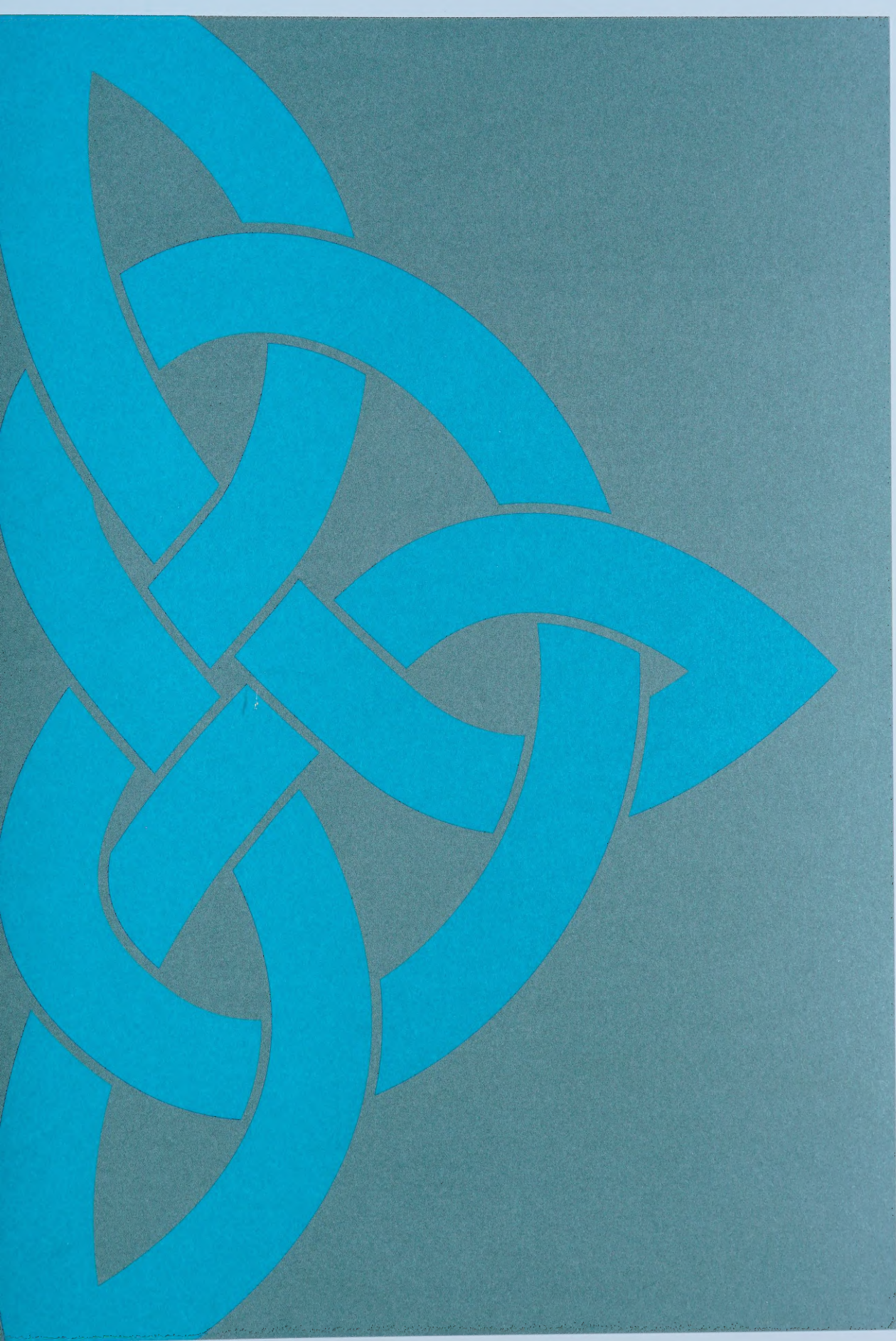
0.62 miles = 1 kilometre

1 mmbtu = 1.054 GJ

0.949 mmbtu = 1 GJ

Natural gas is equated to oil
 on the basis of 6 mcf = 1 BOE.

**Celtic's Annual and Special Meeting of shareholders is scheduled
 for Tuesday, April 24, 2007, at 3:00 p.m., to be held at
 The Metropolitan Centre, 333 Fourth Avenue S.W., Calgary, Alberta.**





Celtic Exploration Ltd.
Suite 500, 505 Third Street S.W.
Calgary, Alberta T2P 3E6